Congestion Management in Restructured Power Systems Using an Optimal Power Flow Framework

Masters Thesis and Project Report

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Executive Summary

The restructuring of the electric power industry has involved paradigm shifts in the real-time control activities of the power grids. Managing dispatch is one of the important control activities in a power system. Optimal power flow (OPF) has perhaps been the most significant technique for obtaining minimum cost generation patterns in a power system with existing transmission and operational constraints.

In this report we look at a modified OPF whose objective is to minimize the absolute MW of rescheduling. In this framework, we also consider dispatching bilateral contracts in case of serious congestion, with the knowledge that any change in a bilateral contract is equivalent to modifying the power injections at both the buyer and the seller buses. This highlights the fact that, in a restructured scenario, contracts between trading entities must be considered as system decision variables (in addition to the usual generation, loads and flows).

The dispatch problem has been formulated with two different objective functions: cost minimization and minimization of transaction deviations. Congestion charges can be computed in both the cases. In a pool market mode, the sellers (competitive generators) may submit their incremental and decremental bid prices in a real-time balancing market. These can then be incorporated in the OPF problem to yield the incremental/decremental change in the generator outputs. Similarly, in the case of the bilateral market mode, every transaction contract may include a compensation price that the buyer-seller pair is willing to accept should its transaction be curtailed. This can then be modeled as a prioritization of the transactions based on the latter's sensitivities to the violated constraint in case congestion occurs.

In this report, we also seek to develop an OPF solution incorporating FACTS devices in a given market mode (pool or bilateral dispatch). FACTS devices assume importance in the context of power system restructuring since they can expand the usage potential of transmission systems by controlling power flows in the network. FACTS devices are operated in a manner so as to ensure that the contractual requirements are fulfilled as far as possible by minimizing line congestion. Various optimization techniques available in the literature have been used to solve OPF problem.

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1 INTRODUCTION

The restructuring of the electric power industry has involved paradigm shifts in the real-time control activities of the power grids. Managing dispatch is one of the important control activities in a power system. Optimal power flow (OPF) has perhaps been the most significant technique for obtaining minimum cost generation patterns in a power system with existing transmission and operational constraints. The role of an independent system operator in a competitive market environment would be to facilitate the complete dispatch of the power that gets contracted among the market players. With the trend of an increasing number of bilateral contracts being signed for electricity market trades, the possibility of insufficient resources leading to network congestion may be unavoidable. In this scenario, congestion management (within an OPF framework) becomes an important issue. Real-time transmission congestion can be defined as the operating condition in which there is not enough transmission capability to implement all the traded transactions simultaneously due to some unexpected contingencies. It may be alleviated by incorporating line capacity constraints in the dispatch and scheduling process. This may involve redispatch of generation or load curtailment. Other possible means for relieving congestion are operation of phase-shifters or FACTS devices.

In this report we look at a modified OPF whose objective is to minimize the absolute MW of rescheduling. In this framework, we consider dispatching the bilateral contracts too in case of serious congestion, with the knowledge that any change in a bilateral contract is equivalent to modifying the power injections at both the buyer and the seller buses. This highlights the fact that, in a restructured scenario, contracts between trading entities must be considered as system decision variables (in addition to the usual generation, loads and flows). Figure 1.1 shows a transaction network [1] in a typical deregulated electricity system. It displays links of data and cash flow between various market players. In the figure, G stands for generator-serving entities (or gencos), D for load or demand-serving entities (LSEs or discos), E for marketers, and ISO for the independent system operator.
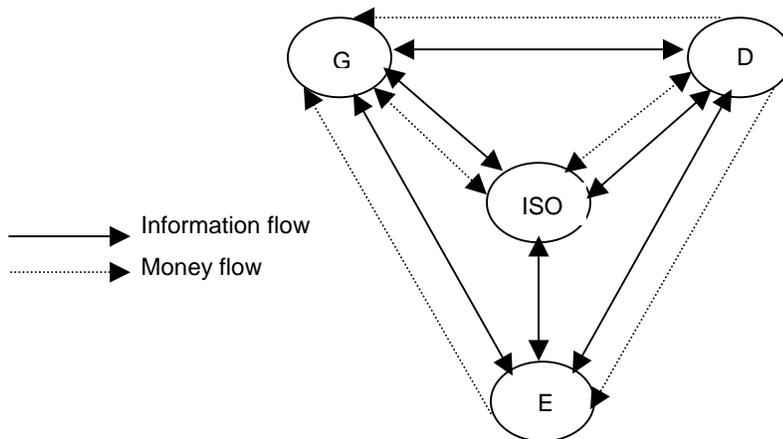
Figure 1.1 Transaction network

The dispatch problem has been formulated with two different objective functions: cost minimization and minimization of transaction deviations. Congestion charges can be computed in both the cases. In a pool market mode, the sellers (competitive generators) may submit their incremental and decremental bidding prices in a real-time balancing market. These can then be incorporated in the OPF problem to yield the incremental/decremental change in the generator outputs. Similarly, in case of a bilateral market mode, every transaction contract may include a compensation price that the buyer-seller pair is willing to accept should its transaction be curtailed. This can then be modeled as a prioritization of the transactions based on the latter's sensitivities to the violated constraint in case congestion occurs.

In this report, we also seek to develop an OPF solution incorporating FACTS devices in a given market mode (pool or bilateral dispatch). FACTS devices assume importance in the context of power system restructuring since they can expand the usage potential of transmission systems by controlling power flows in the network. FACTS devices are operated in a manner so as to ensure that the contractual requirements are fulfilled as far as possible by minimizing line congestion.

Various optimization techniques have been used to solve OPF problems. These may be classified as sequential, quadratic, linear, nonlinear, integer and dynamic programming

methods, Newton-based methods, interior point methods, etc. Nonlinear programming methods involve nonlinear objective and constraint equations. These make up the earliest category of OPF techniques as they can closely model electric power systems. The benchmark paper by Dommel and Tinney [2] discusses a method to minimize fuel costs and active power loss using the penalty function optimization approach. Divi and Kesavan [3] use an adapted Fletcher's quasi-Newton technique for optimization of shifted penalty functions. Linear programming deals with problems with constraints and objective function formulated in linear forms. Sterling and Irving [4] solved an economic dispatch of active power with constraints relaxation using a linear programming approach. Chen et al. [5] developed a successive linear programming (SLP) based method for a loss minimization objective in an ac-dc system. In the SLP approach, the nonlinear OPF problem is approximated to a linear programming problem by linearizing both the objective function as well as the constraints about an operating state. At every iteration, a suboptimal solution is found and the variables are updated to get a new operating state. The process is then repeated until the objective function converges to an optimal level. Megahed et al. [6] have discussed the treatment of the nonlinearly constrained dispatch problem to a series of constrained linear programming problems. Similarly, Waight et al. [7] have used the Dantzig-Wolfe decomposition method to break the dispatch problem into one master problem and several smaller linear programming subproblems. Combinations of linear programming methods with the Newton approach have been discussed in the literature [8]. In [9], Burchett and Happ apply an optimization method based on transforming the original problem to that of solving a series of linearly constrained subproblems using an augmented Lagrangian type objective function. The subproblems are optimized using quasi-Newton, conjugate directions, and steepest descent methods. Quadratic programming is another form of nonlinear programming where the objective function is approximated by a quadratic function and the constraints are linearized. Nanda et al. [10] discuss an OPF algorithm developed using the Fletcher's quadratic programming method. Burchett et al. [11] discuss a successive quadratic programming (SQP) method where the approximation-solution-update process is repeated to convergence just as in the SLP method. In this method, a sequence of quadratic programs is created from the exact analytical first and second derivatives of the

power flow equations and the nonlinear objective function. Interior point methods are fairly new entrants in the field of power system optimization problems. Vargas et al. [12] discussed an interior point method for a security-constrained economic dispatch problem. In [13], Momoh et al. present a quadratic interior point method for OPF problems, economic dispatch, and reactive power planning.

The report is organized as follows. In Chapter 2 we look at congestion management methodologies and how they get modified in the new competitive framework of electricity power markets. A simple example is given for the calculation of congestion charges in a scenario where the objective of optimization is to maximize societal benefit. In Chapter 3, we work out different OPF formulations. Objective functions that are treated include cost minimization and transaction curtailment minimization. Market models involving pool and bilateral dispatches are considered. The possibility of using these formulations in an open access system dispatch module and in real-time balancing markets is discussed. In Chapter 4, we treat the subject of including FACTS devices in the OPF framework. Various device models are considered and then applied in the problem formulation. The impact of these devices on minimizing congestion and transaction deviations is studied. In Chapter 5, the OPF results are displayed on two test systems and inferences are drawn from the same. Further areas of research in this field are then explored in the concluding chapter.

2 CONGESTION MANAGEMENT METHODOLOGIES

2.1 Introduction

In this chapter, we look at congestion management methodologies and how they get modified in the new competitive framework of electricity power markets. A simple example is given for the calculation of congestion charges in a scenario where the objective of optimization is to maximize societal benefit.

2.2 Vertically Integrated Operation

The unbundling of the electric power market has led to the evolution of new organizational structures. *Unbundling* implies opening to competition those tasks that are, in a vertically integrated structure, coordinated jointly with the objective of minimizing the total costs of operating the utility. In such a traditional organizational structure, all the control functions, like automatic generation control (AGC), state estimation, generation dispatch, unit commitment, etc., are carried out by an energy management system. Generation is dispatched in a manner that realizes the most economic overall solution. In such an environment, an optimal power flow can perform the dual function of minimizing production costs and of avoiding congestion in a least-cost manner. Congestion management thus involves determining a generation pattern that does not violate the line flow limits. Line flow capacity constraints, when incorporated in the scheduling program, lead to increased marginal costs. This may then be used as an economic signal for rescheduling generation or, in the case of recurring congestion, for installation of new generation/transmission facilities.

2.3 Unbundled Operation

In a competitive power market scenario, besides generation, loads, and line flows, contracts between trading entities also comprise the system decision variables. The following pool and bilateral competitive structures for the electricity market have evolved/are evolving:

(1)   Single auction power pools, where wholesale sellers (competitive generators) bid to supply power in to a single pool. Load serving entities (LSEs or buyers) then buy wholesale power from that pool at a regulated price and resell it to the retail loads.

(2)   Double auction power pools, where the sellers put in their bids in a single pool and the buyers then compete with their offers to buy wholesale power from the pool and then resell it to the retail loads.

(3)   In addition to combinations of (1) and (2), bilateral wholesale contracts between the wholesale generators and the LSEs without third-party intervention.

(4)   Multilateral contracts, i.e., purchase and sale agreements between several sellers and buyers, possibly with the intervention of third parties such as forward contractors or brokers. In both (3) and (4) the price-quantity trades are up to the market participants to decide, and not the ISO. The role of the ISO in such a scenario is to maintain system security and carry out congestion management.

The contracts, thus determined by the market conditions, are among the system inputs that drive the power system. The transactions resulting from such contracts may be treated as sets of power injections and extractions at the seller and buyer buses, respectively. For example, in a system of n buses, with the generator buses numbered from 1 to m, the nodal active powers may be represented as [14]

$$P_i = P_{po,i} + \sum_{k \in K} P_{T_K,i} + \text{loss compensation}, \ i = 1, 2, \dots m \qquad (2.1)$$

$$D_j = D_{po,j} + \sum_{k \in K} D_{T_K,j}, \ j = m+1, \dots n \qquad (2.2)$$

where

P_i	=	active injected power at generator bus i
D_j	=	active extracted power at load bus j
K	=	set of bilateral / multilateral transactions
$P_{po,I}$	=	pool power injected at bus i
$D_{po,j}$	=	pool power extracted at bus j
$P_{Tk,I}$	=	power injected at bus i in accordance with transaction T_K
$D_{Tk,j}$	=	power extracted at bus j in accordance with transaction T_K
Loss compensation	=	power supplied at bus i by all transaction participants to make good the transmission losses.

2.4 Congestion Management Methodologies

There are two broad paradigms that may be employed for congestion management. These are the *cost-free* means and the *not-cost-free* means [15]. The former include actions like outaging of congested lines or operation of transformer taps, phase shifters, or FACTS devices. These means are termed as *cost-free* only because the marginal costs (and not the capital costs) involved in their usage are nominal. The *not-cost-free* means include:

(1) Rescheduling generation. This leads to generation operation at an equilibrium point away from the one determined by equal incremental costs. Mathematical models of pricing tools may be incorporated in the dispatch framework and the corresponding cost signals obtained. These cost signals may be used for congestion pricing and as indicators to the market participants to rearrange their power injections/extractions such that congestion is avoided.

(2) Prioritization and curtailment of loads/transactions. A parameter termed as *willingness-to-pay-to-avoid-curtailment* was introduced in [14]. This can be an effective instrument in setting the transaction curtailment strategies which may then be incorporated in the optimal power flow framework.

In the next chapter we look at OPF formulations incorporating both (1) and (2) above. These models can be used as part of a real-time open access system dispatch module [16]. The function of this module is to modify system dispatch to ensure secure and efficient system operation based on the existing operating condition. It would use the dispatchable resources and controls subject to their limits and determine the required curtailment of transactions to ensure uncongested operation of the power system.

2.5 Example of Congestion Management in an Economic Dispatch Framework

We now look at an example of calculating optimal bus prices and congestion costs for a power system, wherein an independent company (ISO) controls the transmission network and sets nodal prices that are computed as part of a centralized dispatch. A simple power system is considered here for the calculation of congestion charges. A three-bus system is shown in Figure 2.1 with generator cost/marginal cost and load benefit/marginal benefit

functions as shown. Also shown in the figure are the maximum line flow limits and line susceptances.
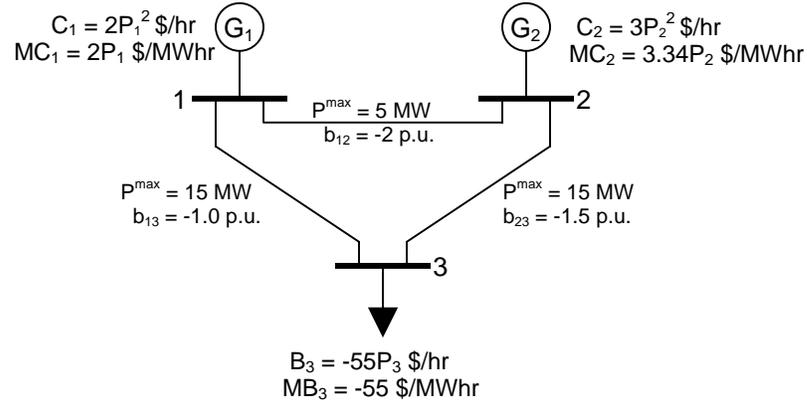
Figure 2.1   Sample power system

For simplicity we make the following approximations:

(1)   Each transmission line is represented by its susceptance b_{ij}.

(2)   A lossless DC power flow model is assumed; i.e., the bus voltage angular differences are assumed to be small and the voltage magnitudes approximately 1.00 p.u.

The real power flow on each line is given by

$$P_{ij} = b_{ij} \cdot (\delta_i - \delta_j) \tag{2.3}$$

where δ_i and δ_j represent the voltage angles at buses i and j, respectively.

The total power injection at bus i is given by

$$P_i = \sum_j P_{ij} \tag{2.4}$$

As mentioned above, we solve this problem in a centralized dispatch framework where the objective is to maximize social benefit. This optimization problem thus seeks to minimize the system operating costs minus the consumer benefit, subject to the binding

line flow inequality constraints and the power flow equality constraints. The problem involves solving a quadratic Lagrangian (quadratic in the decision variables and multipliers).

The variables are given by

$$z = [\underline{P}, \underline{\delta}, \underline{\lambda}, \underline{\mu}] \tag{2.5}$$

where

$\underline{P}$ denotes the net power injections at all the buses

$\underline{\delta}$ denotes the voltage angles

$\underline{\lambda}$ denotes the Lagrangian multipliers for the equality constraints

$\underline{\mu}$ denotes the multipliers for the inequality constraints.

The problem may be thus stated as

$$\min_{P,\delta}\{C_1(P_1) + C_2(P_2) - B_3(P_3)\} \tag{2.6}$$

subject to

$$P_1 = -2\delta_2 - \delta_3 \tag{2.7}$$

$$P_2 = 3.5\delta_2 - 1.5\delta_3 \tag{2.8}$$

$$P_3 = -1.5\delta_2 + 2.5\delta_3 \tag{2.9}$$

$$\left|P_{12}\right| \le P_{12}^{\max}, \left|P_{23}\right| \le P_{23}^{\max}, \left|P_{13}\right| \le P_{13}^{\max} \tag{2.10}$$

In this example, the inequality constraint limiting the flow on line 1-2 is taken as binding. The Lagrangian function for this problem may be given as

$$\ell = 2P_1^2 + 3P_2^2 + 55P_3 + \lambda_1(-2\delta_2 - \delta_3 - P_1) + \lambda_2(3.5\delta_2 - 1.5\delta_3 - P_2) + \lambda_3(-1.5\delta_2 + 2.5\delta_3 - P_3)$$

$$+ \mu_{12}(-2\delta_2 - 5) \tag{2.11}$$

The optimality condition is given by

$$\frac{\partial \ell}{\partial z} = 0 \tag{2.12}$$

and

$$\ell(z) = \frac{1}{2} z^T \cdot \frac{\partial^2 \ell}{\partial z^2} \cdot z + \left[\frac{\partial \ell}{\partial z} \bigg|_{z=0} \right]^T \cdot z \qquad (2.13)$$

From equations (2.12) and (2.13), it can be seen that the optimal value of z may be obtained by solving

$$\frac{\partial^2 \ell}{\partial z^2} \cdot z = - \frac{\partial \ell}{\partial z} \bigg|_{z=0} \qquad (2.14)$$

Solving the problem in the above example yields the following optimal values:

$$z = [16.21 \ 8.06 \ -24.27 \ | \ -2.5 \ -11.21 \ | \ 64.86 \ 48.42 \ 55| \ -21.36]^T \qquad (2.15)$$

The Lagrange multipliers $\underline{\lambda} = [64.86 \ 48.42 \ 55]^T$ can be interpreted as the optimal nodal prices at each of the three buses in \$/MWhr. In other words, if these had been used as the bus prices, the generator and load responses to these prices would have been the same as what was obtained in the above optimal dispatch.

We now compute the congestion charges (for the flow on each transmission line). The congestion charge may be looked upon as the inherent cost of transmitting power across the line. A simple way to compute this is given here. The congestion charge c_{ij} for line ij is the difference in the congestion costs c_i and c_j at buses i and j, respectively; i.e.,

$$c_{ij} = c_j - c_i, \qquad (2.16)$$

Now, each bus nodal price λ_i is made up of three components, viz., the marginal cost of generation at the slack bus, the marginal cost of losses, and the congestion cost. Hence,

$$\lambda_i = - \frac{\partial C_1(P_1)}{\partial P_1} \cdot \frac{\partial P_1}{\partial P_i} + c_i \qquad (2.17)$$

where $C_1(P_1)$ is the cost function at bus 1, which has been considered as the slack bus in this example.

We have considered the lossless case in this example. Hence we have,

$$c_{ij} = \lambda_j - \lambda_i, \qquad (2.18)$$

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Thus the congestion charge for any line ij may be computed as the difference in the nodal prices between buses i and j. The values obtained in this problem are $c_{12} = -16.43$ $/MWhr, $c_{23} = 6.58$ $/MWhr, $c_{13} = -9.86$ $/MWhr.

2.6 Congestion Management Using Pricing Tools

In [15], Glavitsch and Alvarado discuss congestion pricing as may be done by an ISO in the absence of information on the marginal costs of the generators. The methodology suggested involves observing the behavior of generators under a variety of conditions, based on which quadratic coefficients for all generators may be inferred.

In [17], Bhattacharya et al. discuss the method of market splitting to alleviate transmission congestion. The basic principle of this method lies in sending price signals that either exceed or are less than the marginal costs to generators and thereby affecting a change in the generation pattern. The market is "split" into different bid areas and the area-prices are calculated for each bid area using a "capacity fee."

In the next chapter we work out different OPF formulations in the various market modes discussed earlier.

3 OPTIMAL DISPATCH METHODOLOGIES IN DIFFERENT MARKET STRUCTURES

3.1 Introduction

In this chapter, we look at ways of managing the power dispatch problem in the emerging electricity market structures. The operating strategies that may be used by the ISO in different market modes have been explored and test cases have been studied to determine the compatibility of the strategies with the market environment. Emphasis is placed on dealing with congestion management.

The conventional OPF problem comprises scheduling the power system controls to optimize a given objective function under a set of nonlinear inequality constraints and equality constraints. Under a deregulated environment, mechanisms for competition and trading are created for the market players. This leads to the introduction of new OPF controls. In this chapter we look at how to deal with these controls.

The fundamental entity in all competitive market structures is an ISO. "Successful" trading requires that the ISO match the power bids from the supply side (gencos) with the offers from the demand side (discos). This is true for all market structures. The important way in which market structures differ is in the manner of the main contractual system that is followed by the market players on both the supply and demand sides. We look at two different market modes, viz., pool dispatch and bilateral dispatch.

3.2 Pool Dispatch

3.2.1 Pool structure

Interconnected system operation becomes significant in a deregulated environment. This is because the market players are expected to treat power transactions as commercial business instruments and seek to maximize their economic profits. Now when several gencos decide to interchange power, complications may arise. An economic dispatch of the interconnected system can be obtained only if all the relevant information, viz., generator curves, cost curves, generator limits, commitment status, etc., is exchanged

among all the gencos. To overcome this complex data exchange and the resulting non-optimality, the gencos may form a power pool regulated by a central dispatcher. The latter sets up the interchange schedules based on the information submitted to it by the gencos. While this arrangement minimizes operating costs and facilitates system-wide unit commitment, it also leads to several complexities and costs involved in the interaction with the central dispatcher. Conventionally, the optimal operation of a power system has been based on the economic criterion of loss minimization, i.e., maximization of societal benefit. Pool dispatch follows the same criterion but with certain modifications necessitated by the coexistence of the pool market with a short-term electricity spot market. Namely, these effects are demand elasticities and the variation in the spot price with the purchaser's location on the grid. The existence of the spot market or bilateral market behind the scene does not explicitly affect the operation of the ISO.

3.2.2 Pool dispatch formulation

Neglecting the effects of price elasticities and location, the dispatch formulation may be stated as

$$\min_{P_{Gi}, P_{Dj}} \sum_i C_i(P_{Gi}) - \sum B_j(P_{Dj}) \tag{3.1}$$

subject to

$$\begin{aligned} g(x,u) &= 0 \\ h(x,u) &\leq 0 \end{aligned} \tag{3.2}$$

where

 g and h are the sets of system operating constraints, including system power flow equations and line flow limits

 u is the set of control variables, viz., active powers at the generator and load buses

 x is the set of dependent variables

 i and j are the set of gencos and discos, respectively

This OPF uses the bids and offers submitted by the participants and sets the nodal prices (that are obtained as the Lagrangian multipliers), which are in turn used to charge for the power consumption at every node. The vectors of generation and load are denoted as P_{Gi}

and P_{Dj}, respectively. The nodal prices applied to the generation and load controlled by players i and j are obtained as a byproduct of the OPF and are represented as λ_i and λ_j, respectively. The cost and benefit functions of each generator and load are denoted by C_i and B_j, respectively. The cost and benefit functions are assumed to be well described by quadratic functions.

$$C_i(P_{G_i}) = a_{G,i} \cdot P_{G_i}^2 + b_{G,i} \cdot P_{G_i} + c_{G,i}, \quad i \in G \tag{3.3}$$

$$B_j(P_{D_j}) = a_{D,i} \cdot P_{D_j}^2 + b_{D,j} \cdot P_{D_j} + c_{D,j}, \quad j \in D \tag{3.4}$$

where G represents the set of all gencos and D represents the set of discos.

The equality constraint may be written as

$$\sum_j P_{D_j} - \sum_i P_{G_i} + L = 0 \tag{3.5}$$

where L is the transmission loss function.

The capacity constraint (inequality) may be given as

$$P_{G_i} - P_{G_i,\max} \leq 0 \tag{3.6}$$

Problem (3.1) leads to the solution and Kuhn-Tucker conditions given as

$$\frac{\partial B_j}{\partial P_{D_j}} - p_j - \lambda_j(1 + \frac{\partial L}{\partial P_{D_j}}) + \sum_k \pi_k \frac{\partial h_k}{\partial P_{D_j}} = 0$$

$$\frac{\partial C_i}{\partial P_{G_i}} - \lambda_i(1 - \frac{\partial L}{\partial P_{G_i}}) - \mu_i - \sum_k \pi_k \frac{\partial h_k}{\partial P_{G_i}} = 0$$

$$\mu_i(P_{G_i} - P_{G_i,\max}) = 0 \quad \text{and} \quad \mu_i \geq 0$$

$$\pi_k h_k = 0 \quad \text{and} \quad \pi_k \geq 0 \tag{3.7}$$

where λ represents the system incremental cost (dual multiplier on the equality constraint) and μ and π represent the sets of Kuhn-Tucker dual variables on the capacity and operating constraints, respectively.

3.2.3 Example of corrective rescheduling in pool dispatch

When the system is insecure and there are violations in the system, the objective of the pool central dispatcher is to eliminate the system overload and come up with the corrective rescheduling to eliminate the violations as fast as possible. Minimum operating cost, minimum number of controls, or minimum shift from the optimum operation may be used as the objective function. We now look at an OPF example where the objective function is to minimize the rescheduling of generation.
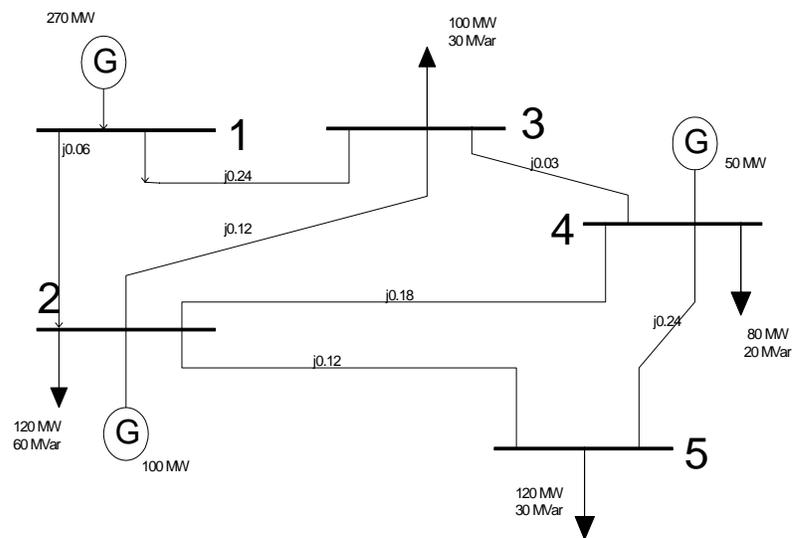
Figure 3.1 Three-generator five-bus system

Consider a five-bus system as shown in Figure 3.1. The system data is given in Table 3.1

Table 3.1   Bus data for Figure 3.1

Bus number	Load MW	MVar	Gen MW	Gen min MW	Gen max MW	Voltage setpoint	Cost ($/MWhr)
1 (slack)	0	0	270	0	1000	1.05	15
2	120	60	100	100	400	1.02	17
3	100	30	-	-	-	-	-
4	80	20	50	50	300	1.02	19
5	120	30	-	-	-	-	-

Table 3.2   Line data for Figure 3.1

From bus	To bus	p.u. impedance	MVA rating	Base case power flow(MW)
1	2	j0.06	150	197.27
1	3	j0.24	100	72.72
2	3	j0.12	50	46.39
2	4	j0.18	100	34.29
2	5	j0.12	120	96.60
3	4	j0.03	100	19.12
4	5	j0.24	100	23.40

The base case power flow for the system shows (Table 3.2) that congestion occurs on line 1-2. The aim is to reschedule generation to remove this congestion and any other induced congestion. We first compute the sensitivities of line flow P_{jk} to changes in generation P_{G1}, P_{G2}, P_{G4}. For that we use the chain rule:

$$\frac{\partial P_{jk}}{\partial P_{Gi}} = \left[\frac{\partial P_{jk}}{\partial \theta}\right]^T \left[\frac{\partial f^P}{\partial \theta}\right]^{-1} \left[\frac{\partial f^P}{\partial P_{Gi}}\right] \tag{3.8}$$

where f_i^p represents the power flow equation at bus i, which is given as

$$\sum \frac{1}{x_{ij}}(\theta_i - \theta_j) - (P_{Gi} - P_{Di}) = 0 \tag{3.9}$$

In matrix formulation the power flow equation is $\theta = -B^{-1}P$, where B is the bus susceptance matrix computed from the line impedance data. Fixing bus 1 as the slack, we can then get the equations for line flows and the line flow sensitivities to generation. The sum of all the products of line flow sensitivities with changes in generation (rescheduling) gives the overload in that particular line.

In this particular example, the objective is to minimize the rescheduling of generation required to limit the flow on line 1-2 to 150 MVA. The OPF problem can then be given as

$$\min(\Delta P_{G_1}^+ + \Delta P_{G_1}^- + \Delta P_{G_2}^+ + \Delta P_{G_2}^- + \Delta P_{G_4}^+ + \Delta P_{G_4}^-) \tag{3.10}$$

subject to

$$\Delta P_{G_1}^+ - \Delta P_{G_1}^- + \Delta P_{G_2}^+ - \Delta P_{G_2}^- + \Delta P_{G_4}^+ - \Delta P_{G_4}^- = 0 \tag{3.11}$$

and

$$\frac{\partial P_{12}}{\partial P_{G_2}} \left[\Delta P_{G_2}^+ - \Delta P_{G_2}^-\right]^T + \frac{\partial P_{12}}{\partial P_{G_4}} \left[\Delta P_{G_4}^+ - \Delta P_{G_4}^-\right]^T = -0.47 \tag{3.12}$$

where 0.47 is the overload on line 1-2.

This OPF problem can be solved to minimize the rescheduling of generation. We get the result that bus 1 must drop its generation by 56.2 MW, bus 2 must raise its generation by 52.37 MW, and bus 4 must raise its generation by 3.88 MW;

$$\Delta P_{G_1}^- = 56.2 \text{ MW}$$
$$\Delta P_{G_2}^+ = 52.37 \text{ MW}$$
$$\Delta P_{G_4}^+ = 3.88 \text{ MW} \tag{3.13}$$

3.3 Bilateral Dispatch

3.3.1 Bilateral market structure

The conceptual model of a bilateral market structure is that gencos and discos enter into transaction contracts where the quantities traded and the prices are at their own discretion and not a matter for the ISO; i.e., a bilateral transaction is made between a genco and a disco without third party intervention. These transactions are then submitted to the ISO. In the absence of any congestion on the system, the ISO simply dispatches all the transactions that are requested, making an impartial charge for the service.

3.3.2 Bilateral dispatch formulation

In a bilateral market mode, the purpose of the optimal transmission dispatch problem is to minimize deviations from transaction requests made by the market players. The goal is to make possible all transactions without curtailments arising from operating constraints. The new set of rescheduled transactions thus obtained will be closest to the set of desired transactions, while simultaneously satisfying the power flow equations and operating constraints. One of the most logical ways of rescheduling transactions is to do it on the basis of rationing of transmission access. This may be modeled as a user-pay scheme with "willingness-to-pay" surcharges to avoid transmission curtailment. The mathematical formulation of the dispatch problem may then be given as

$$\min f(x, u)$$

where

$$f(u, x) = [(u - u^o)^T \cdot A] \cdot W \cdot [(u - u^o)^T \cdot A]^T \tag{3.14}$$

subject to

$$g(x, u) = 0$$
$$h(x, u) \leq 0$$

where

W is a diagonal matrix with the surcharges as elements

A is a constant matrix reflecting the curtailment strategies of the market participants

u and u^o are the set of control variables, actual and desired

x is the set of dependent variables

g is the set of equality constraints, viz., the power flow equations and the contracted transaction relationships,

h is the set of system operating constraints including transmission capacity limits

The bilateral case can be modeled in detail. We consider transactions in the form of individual contracts where a seller i injects an amount of power T_{ij} at one generator bus and the buyer j extracts the same amount at a load bus. Let the power system consist of n buses with the first m assumed to be seller buses and the remaining n-m as buyer buses. One particular bus (bus 1) may be designated as the slack to take into account

transmission losses. The total power injected/extracted at every bus may be given by the summation of all individual transactions carried out at those buses. Thus,

$$for\ i = 2\ to\ m,\ P_i = \sum_j T_{ij},\ and$$

$$for\ j = m+1\ to\ n,\ P_j = \sum_i T_{ij} \tag{3.15}$$

The transactions T_{ij} also appear in the power flow equality constraints since they act as the control variables along with the usual generator bus voltages. The set of control variables can thus be represented as $u = \{\sum T_{ij}, V\}^T$, where V is the vector of generator bus voltages.

The real and reactive power flow equations can be written in the usual form represented by $g(x, u) = 0$

The transaction curtailment strategy is implemented by the ISO in collaboration with the market participants. In the case of bilateral dispatch, this strategy concerns the individual power contracts. One such strategy is such that, in case of an individual contract, the curtailment of the transacted power injected at the genco bus must equal the curtailment of the transacted power extracted at the disco bus.

In this case, we may rewrite the dispatch formulation as

$$\min f(x, u)$$

where

$$f(x, u) = \sum_{i=2}^{m} \sum_{j=m+1}^{n} w_{ij} \cdot (T_{ij} - T_{ij}^0)^2 \tag{3.16}$$

where

w_{ij} = the willingness to pay factor to avoid curtailment of transaction

T_{ij}^0 = the desired value of transaction T_{ij}

3.3.3 Test results

We consider a six-bus system representing a deregulated market with bilateral transactions. An OPF will be solved for this system to determine the optimal generation schedule that satisfies the objective of minimizing deviations from the desired transactions.

Table 3.3 provides the system data pertaining to generation and load. Table 3.4 provides the system network data. Figure 3.2 shows the system network configuration. Buses 1 and 2 are genco buses and, being PV buses, the voltages here are specified exactly. At the other buses, the allowable upper and lower limits of voltage are specified. The losses are assumed to be supplied only by the generator at bus 1.
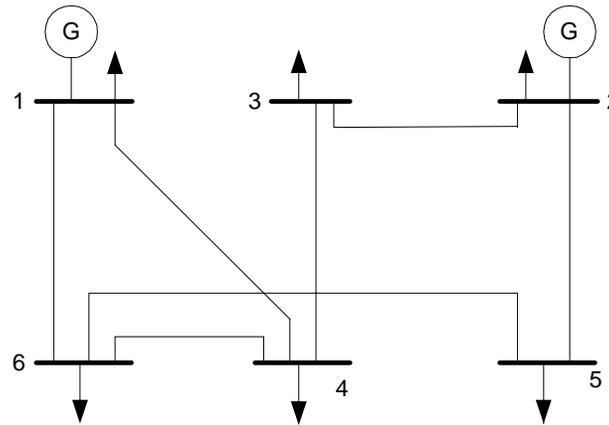
Figure 3.2   Two-generator six-bus system

Table 3.3 System data

Bus	Generation capacity, MW	Generator cost characteristic, \$/hr	Voltage, pu
1	$100 \leq P_1 \leq 400$	$P_1^2 + 8.5P_1 + 5$	1.05
2	$50 \leq P_2 \leq 200$	$3.4P_2^2 + 25.5P_2 + 9$	1.06
3	-	-	$0.9 \leq V_3 \leq 1.1$
4	-	-	$0.9 \leq V_4 \leq 1.1$
5	-	-	$0.9 \leq V_5 \leq 1.1$
6	-	-	$0.9 \leq V_6 \leq 1.1$

Table 3.4   System network data

From bus – to bus	Resistance, pu	Reactance, pu	Line charging admittance, pu
1-4	0.0662	0.1804	0.003
1-6	0.0945	0.2987	0.005
2-3	0.0210	0.1097	0.004
2-5	0.0824	0.2732	0.004
3-4	0.1070	0.3185	0.005
4-6	0.0639	0.1792	0.001
5-6	0.0340	0.0980	0.004

In this case, bilateral contracts have been considered between each genco and each disco. Table 3.5 shows the desired power transactions.

Table 3.5   Desired transactions before curtailment

Bus #	Desired transactions, MW
1	20.0
2	30.0
3	35.0
4	50.0
5	42.0
6	55.0

Three strategies for the curtailment of transactions are adopted for congestion management:

(1)   The curtailment on the disco loads is assumed to be linear. In this case, all the willingness to pay factors are taken to be equal.

(2)   Same as case (1), except that the willingness to pay price premium of loads on buses 1 to 3 is assumed to be twice that of loads on buses 4 to 6.

(3) In this case, the price premium of loads on buses 4 to 6 is assumed to be twice that of loads on buses 1 to 3.

The OPF problem is solved using the MINOS-5.0 nonlinear programming solver in the Generalized Algebraic Modeling Systems (GAMS) programming environment [18].

Table 3.6 shows the constrained generation and load data obtained from the OPF solution. It can be seen that the willingness to pay and the participants' curtailment strategy are two factors that significantly affect the constrained dispatch. The higher the willingness to pay, the less is the curtailment of that particular transaction. The curtailment strategies implemented have complex effects. These factors not only affect the curtailment of its own transaction, but will also impact that of other transactions.

Table 3.6 Constrained generation and load data after running OPF

Bus #	Constrained generation and load, MW		
	Case (1)	Case (2)	Case (3)
1	109.63	109.62	109.68
2	124.24	124.41	123.60
3	34.72	34.93	33.95
4	48.87	48.86	48.94
5	40.74	40.72	40.81
6	53.99	53.97	54.05

3.4 Treatment of Transaction-Based Groups

In a competitive market scenario, relationships among market players may develop over time and may lead to the formation of electricity supply and consumption groups. The concept of a group as a collection of buyers, sellers, and market brokers functioning together in a cohesive manner has to be dealt with. The formation of such transaction-based groups in a power system necessitates changes in power dispatch. In the following sections we look at dispatch formulations taking into account the group concept.

3.4.1 Dispatch formulations

Here the concern is to make possible a group transfer without curtailment, even if the individual generators within the group or utility have to be rescheduled. The objective function is

$$\min f(x,u)$$

where

$$f(u,x) = \sum_{k=1}^{K}[w_k \cdot (\sum_{i=2}^{m}T_{ik} - \sum_{i=2}^{m}T_{ik}^0)^2] \qquad (3.17)$$

where

w_k = the willingness to pay factor to avoid curtailment of the kth group transaction

T_{ik}^0 = the desired value of transaction T_{ij}

In this group curtailment dispatch formulation, there is the need to develop a strategy to allocate the total group power curtailment among all the group participants. That is, if the genco powers within a group need to be curtailed, the resulting shortfall has to be allocated to all the group discos in accordance with some predetermined strategy.

Another way of implementing curtailment of group transactions is by minimizing the change to every injected or extracted power transaction at the generator bus and load bus of a group based on the willingness to pay factors. In this case, the objective function may be expressed as

$$\min f(x,u)$$

where

$$f(u,x) = \sum_{k=1}^{K}\sum_{i=2}^{m}[w_{ik} \cdot (T_{ik} - T_{ik}^0)^2] \qquad (3.18)$$

where w_{ik} = the willingness to pay factor to avoid curtailment of the injected power block T_{ik}.

In this optimal transmission dispatch problem, all power transactions are required to be as close as possible to the initial desired power transfers, and the curtailment decisions are

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based on the market players' willingness to pay to avoid curtailment, their preferred curtailment strategies, and on the system security conditions. The dispatch procedure starts with the market participants submitting their multilateral transactions to the ISO. If the operating and capacity constraints are satisfied while all the desired transactions are dispatched, there is no need to go through the curtailment routine. Otherwise the optimal dispatch models described above (Sections 3.2.2, 3.3.2, 3.4.1) are used to curtail the requested power transfers. Finally, the original/curtailed power transfers are dispatched and the ISO buys the required regulating power at bus 1 to compensate for transmission losses.

3.4.2 Test case

We now look at an optimal transmission dispatch problem in a deregulated market having transaction-based groups. We consider the IEEE 14-bus system here (Figure 3.3).
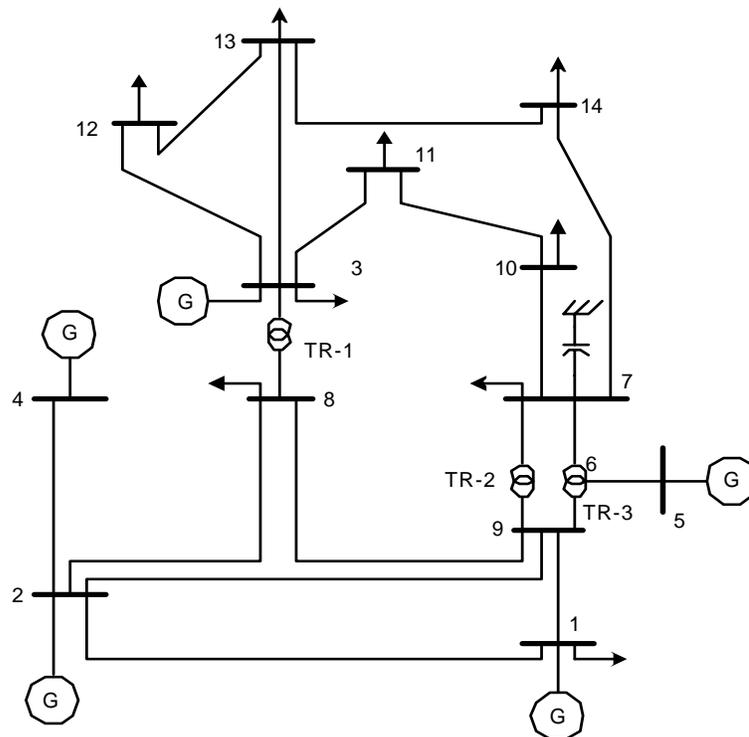

Figure 3.3 IEEE five-generator fourteen-bus system

Some slight modifications are made. Bus 4 is renumbered as bus 1 and it is assumed that this bus is contracted by the system ISO to provide for the transmission losses; i.e., bus 1

is the system slack bus. This bus, in addition to bus 5, is usually shown connected to a synchronous condenser. But in this problem, we treat bus 1 as a generator bus owned by a genco. Similarly, bus 5 is treated as a PV-bus in the problem.

Table 3.7 provides the generation bus data. Table 3.8 provides the system network data. The voltages at the genco buses are specified since they are P-V buses, whereas at the disco buses, the allowable upper and lower limits of voltage are specified.

Table 3.7 Generation bus data

Bus	Generation capacity, MW	Generator cost characteristic, \$/hr	Voltage, pu
1	-	-	1.01
2	$20 \le P_2 \le 100$	$0.5 P_2^2 + 3.51 P_2 + 44.4$	1.045
3	$20 \le P_3 \le 100$	$0.5 P_3^2 + 3.89 P_3 + 40.6$	1.07
4	$50 \le P_4 \le 200$	$0.5 P_4^2 + 2.45 P_4 + 105.0$	1.06
5	-	-	1.09

Table 3.8   System network data

From bus – to bus	Resistance, pu	Reactance, pu	Line charging admittance, pu
4-8	0.05403	0.22304	0.0246
2-8	0.05695	0.17388	0.0170
1-9	0.06701	0.17103	0.0173
9-8	0.01335	0.04211	0.0064
4-2	0.01938	0.05917	0.0264
2-1	0.04699	0.19797	0.0219
5-6	0.00000	0.17615	0.0000
2-9	0.05811	0.17632	0.0187
6-7	0.00000	0.11001	0.0000

Table 3.8   (cont.)

7-10	0.03181	0.08450	0.0000
3-11	0.09498	0.19890	0.0000
3-12	0.12291	0.25581	0.0000
3-13	0.06615	0.13027	0.0000
7-14	0.12711	0.27038	0.0000
10-11	0.08205	0.19207	0.0000
12-13	0.22092	0.19988	0.0000
13-14	0.17093	0.34802	0.0000

We now assume that there are two groups in this power system: Group 1 consists of buses 2 and 3 and makes transfers to disco buses 7, 9, 11, and 14. Group 2 consists of the single genco bus 4 and makes tranfers to disco buses 8, 10, 12, and 13. Table 3.9 shows the desired power generation and load for both groups.

Table 3.9   Desired generation and load before curtailment

Bus #	Pre-curtailment MW
1	38.1
2	138.4
3	92.6
4	213.5
5	0.0
6	0.0
7	54.3
8	155.4
9	91.5
10	16.8
11	56.6
12	13.1
13	28.2
14	28.6

It is seen from the power flow solution that the dispatch of the contracted transactions without any curtailment leads to overloading of the lines between buses 3 and 11, and buses 7 and 9. Therefore, to remove this congestion and to ensure that the system security limits are not violated, the ISO needs to curtail the power transactions

The following four strategies for the curtailment of transactions are adopted for congestion management. The results are shown in Table 3.10.

(1) Both groups 1 and 2 employ the group curtailment formulation as described by (3.17). The curtailment on the disco loads is assumed to be linear. The total group power curtailment is taken as a linear combination of the individual disco curtailments. In this case, all the willingness to pay factors are taken to be equal to unity.

(2) Same as case (1), except that the willingness to pay price premium of the players in group 2 is assumed to be twice that of the players in group 2.

(3) In this case, group 1 employs the curtailment strategy given in (3.17), whereas group 2 adopts the curtailment formulation described in (3.16). Willingness to pay premiums are maintained at unity.

(4) Same as case (3), except that the willingness to pay premiums on the transactions between buses 4 and 10, and buses 4 and 12, are doubled.

Table 3.10 shows the constrained generation and load data obtained from the OPF solutions using the four curtailment strategies.

Table 3.10   Constrained generation and load data after running OPF

Bus #	Constrained generation and load, MW			
	Case (1)	Case (2)	Case (3)	Case (4)
(group #1)				
2 (genco)	138.42	138.40	138.51	138.47
3 (genco)	78.53	79.76	87.20	84.73
7	52.11	52.33	53.58	53.04
9	86.37	87.20	89.71	88.33
11	53.10	53.24	55.13	54.75
14	25.40	25.42	27.32	27.11
(group #2)				
4 (genco)	204.10	197.31	207.01	210.75
8	149.62	144.36	155.20	155.22
10	15.53	14.96	12.84	15.32
12	12.62	12.25	11.25	12.81
13	26.37	25.81	27.78	27.65
(loss compensator)				
1 (genco)	35.41	35.23	35.62	36.27

The optimal dispatch gives an uncongested system solution (Table 3.10); i.e., all the line overloads are removed. In case (1), both the groups use the same curtailment strategies with identical willingness-to-pay factors, and this results in all power transactions getting curtailed in varying degrees. In case (2), the willingness to pay of group 1 is increased. This does not lead to a proportionate reduction in the curtailment of the transactions in group 1 or a proportionate increase in the curtailment of transactions in group 2. In case (3), the use of two different curtailment strategies for the two groups seems to affect some transactions more than others. For instance, the transaction between buses 4 and 10, and buses 4 and 12, get relatively heavily curtailed. This is remedied in case (4) where the willingness to pay for both these pairs of players is doubled.

3.5 Conclusions

This chapter has focused on the dispatch curtailment problem in a competitive market scenario. A framework for price-based operation under these conditions is explored and an optimal transmission dispatch methodology is developed. The case studies show the complex interactions between the market participants.

4 OPTIMAL DISPATCH USING FACTS DEVICES IN DEREGULATED MARKET STRUCTURES

4.1 Introduction

In the previous chapters we have looked at congestion management in deregulated power systems using models that include pricing tools such as prioritization and curtailment of transactions. In this chapter we look at treating congestion management with the help of flexible AC transmission (FACTS) devices. We consider an integrated approach to incorporate the power flow control needs of FACTS in the OPF problem for alleviating congestion. Two main types of devices are considered here, namely, thyristor controlled series compensators (TCSC) and thyristor controlled phase angle regulators (TCPAR).

The concept of flexible AC transmission systems (FACTS) was first proposed by Hingorani [19]. FACTS devices have the ability to allow power systems to operate in a more flexible, secure, economic, and sophisticated way. Generation patterns that lead to heavy line flows result in higher losses, and weakened security and stability. Such patterns are economically undesirable. Further, transmission constraints make certain combinations of generation and demand unviable due to the potential of outages. In such situations, FACTS devices may be used to improve system performance by controlling the power flows in the grid. Studies on FACTS so far have mainly focused on device developments and their impacts on the power system aspects such as control, transient and small signal stability enhancement, and damping of oscillations [20]-[23]. Here we look at solving the OPF problem in a power system incorporating FACTS devices. As we have seen in the earlier chapters, different solution approaches are possible to solve the OPF problem. The main conventional control variables are the generation MWs when the DC power flow model is used. With the increased presence of independent gencos in the deregulated scenario, the operation of power systems would require more sophisticated means of power control. FACTS devices can meet that need.

4.2 Static Modeling of FACTS Devices

For the optimal power dispatch formulation using FACTS controllers, only the static models of these controllers have been considered here [24]. It is assumed that the time constants in FACTS devices are very small and hence this approximation is justified.

4.2.1 Thyristor-controlled series compensator (TCSC)

Thyristor-controlled series compensators (TCSC) are connected in series with the lines. The effect of a TCSC on the network can be seen as a controllable reactance inserted in the related transmission line that compensates for the inductive reactance of the line. This reduces the transfer reactance between the buses to which the line is connected. This leads to an increase in the maximum power that can be transferred on that line in addition to a reduction in the effective reactive power losses. The series capacitors also contribute to an improvement in the voltage profiles.

Figure 4.1 shows a model of a transmission line with a TCSC connected between buses i and j. The transmission line is represented by its lumped π-equivalent parameters connected between the two buses. During the steady state, the TCSC can be considered as a static reactance $-jx_c$. This controllable reactance, x_c, is directly used as the control variable to be implemented in the power flow equation.
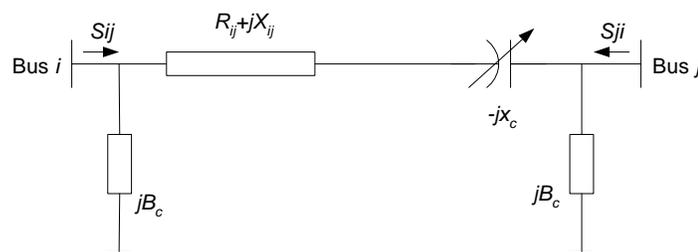

Figure 4.1 Model of a TCSC

Let the complex voltages at bus i and bus j be denoted as $V_i \angle \delta_i$ and $V_j \angle \delta_j$, respectively. The complex power flowing from bus i to bus j can be expressed as

$$S_{ij}^* = P_{ij} - jQ_{ij} = V_i^* I_{ij}$$

$$= V_i^* [(V_i - V_j)Y_{ij} + V_i(jB_c)]$$

$$= V_i^2[G_{ij} + j(B_{ij} + B_c)] - V_i^* V_j (G_{ij} + jB_{ij}) \tag{4.1}$$

where

$$G_{ij} + jB_{ij} = 1/(R_L + jX_L - jX_C) \tag{4.2}$$

Equating the real and imaginary parts of the above equations, the expressions for real and reactive power flows can be written as

$$P_{ij} = V_i^2 G_{ij} - V_i V_j G_{ij} \cos(\delta_i - \delta_j) - V_i V_j B_{ij} \sin(\delta_i - \delta_j) \tag{4.3}$$

$$Q_{ij} = -V_i^2 (B_{ij} + B_c) - V_i V_j G_{ij} \sin(\delta_i - \delta_j) + V_i V_j B_{ij} \cos(\delta_i - \delta_j) \tag{4.4}$$

Similarly, the real and reactive power flows from bus j to bus i can be expressed as

$$P_{ji} = V_j^2 G_{ij} - V_i V_j G_{ij} \cos(\delta_i - \delta_j) + V_i V_j B_{ij} \sin(\delta_i - \delta_j) \tag{4.5}$$

$$Q_{ij} = -V_j^2 (B_{ij} + B_c) + V_i V_j G_{ij} \sin(\delta_i - \delta_j) + V_i V_j B_{ij} \cos(\delta_i - \delta_j) \tag{4.6}$$

The active and reactive power loss in the line can be calculated as

$$P_L = P_{ij} + P_{ji}$$

$$= V_i^2 G_{ij} + V_j^2 G_{ij} - 2V_i V_j G_{ij} \cos(\delta_i - \delta_j) \tag{4.7}$$

$$Q_L = Q_{ij} + Q_{ji}$$

$$= -V_i^2 (B_{ij} + B_c) - V_j^2 (B_{ij} + B_c) + 2V_i V_j B_{ij} \cos(\delta_i - \delta_j) \tag{4.8}$$

These equations are used to model the TCSC in the OPF formulations.

4.2.2 Thyristor-controlled phase angle regulator (TCPAR)

In a thyristor-controlled phase angle regulator, the phase shift is achieved by introducing a variable voltage component in perpendicular to the phase voltage of the line. The static model of a TCPAR having a complex tap ratio of 1:a∠α and a transmission line between bus i and bus j is shown in Figure 4.2.
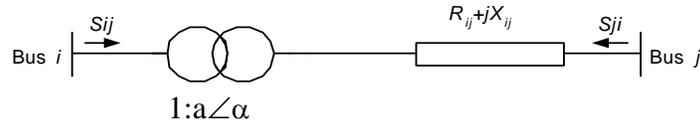

Figure 4.2 Model of TCPAR

The real and reactive power flows from bus i to bus j can be expressed as

$$P_{ij} = \text{Re}\{V_i^*[(a^2V_i - a^*V_j)Y_{ij}]\}$$

$$= a^2V_i^2G_{ij} - aV_iV_jG_{ij}\cos(\delta_i - \delta_j + \alpha) - aV_iV_jB_{ij}\sin(\delta_i - \delta_j + \alpha) \qquad (4.9)$$

and

$$Q_{ij} = -\text{Im}\{V_i^*[(a^2V_i - a^*V_j)Y_{ij}]\}$$

$$= -a^2V_i^2G_{ij} - aV_iV_jB_{ij}\cos(\delta_i - \delta_j + \alpha) - aV_iV_jG_{ij}\sin(\delta_i - \delta_j + \alpha) \qquad (4.10)$$

Similarly, real and reactive power flows from bus j to bus i can be written as

$$P_{ji} = \text{Re}\{V_j^*[(V_j - aV_i)Y_{ij}]\}$$

$$= V_j^2G_{ij} - aV_iV_jG_{ij}\cos(\delta_i - \delta_j + \alpha) + aV_iV_jB_{ij}\sin(\delta_i - \delta_j + \alpha) \qquad (4.11)$$

and

$$Q_{ji} = -\text{Im}\{V_j^*[(V_j - aV_i)Y_{ij}]\}$$

$$= -V_j^2B_{ij} + aV_iV_jB_{ij}\cos(\delta_i - \delta_j + \alpha) + aV_iV_jG_{ij}\sin(\delta_i - \delta_j + \alpha) \qquad (4.12)$$

The real and reactive power loss in the line having a TCPAR can be expressed as

$$P_l = P_{ij} + P_{ji}$$

$$= a^2V_i^2G_{ij} + V_j^2G_{ij} - 2V_iV_jG_{ij}\cos(\delta_i - \delta_j + \alpha) \qquad (4.13)$$

$$Q_l = Q_{ij} + Q_{ji}$$

$$= -a^2V_i^2B_{ij} - V_j^2B_{ij} + 2V_iV_jB_{ij}\cos(\delta_i - \delta_j + \alpha) \qquad (4.14)$$

This mathematical model makes the Y-bus asymmetrical. In order to make the Y-bus symmetrical, the TCPAR can be simulated by augmenting the existing line with additional power injections at the two buses. The injected active and reactive powers at bus i (ΔP_i, ΔQ_i) and bus j (ΔP_j, ΔQ_j) are given as

$$\Delta P_i = -a^2V_i^2G_{ij} - aV_iV_j[G_{ij}\sin(\delta_i - \delta_j) - B_{ij}\cos(\delta_i - \delta_j)] \qquad (4.15)$$

$$\Delta P_j = -aV_iV_j[G_{ij}\sin(\delta_i - \delta_j) + B_{ij}\cos(\delta_i - \delta_j)] \qquad (4.16)$$

$$\Delta Q_i = a^2V_i^2B_{ij} + aV_iV_j[G_{ij}\cos(\delta_i - \delta_j) + B_{ij}\sin(\delta_i - \delta_j)] \qquad (4.17)$$

$$\Delta Q_j = -aV_iV_j[G_{ij}\cos(\delta_i - \delta_j) - B_{ij}\sin(\delta_i - \delta_j)] \qquad (4.18)$$

These equations will be used to model the TCPAR in the OPF formulation.

The injection model of the TCPAR is shown in Figure 4.3
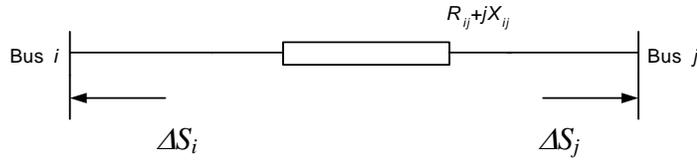
Figure 4.3 Injection model of TCPAR

4.2.3 Static VAr compensator (SVC)

The static VAr compensator (SVC) is generally used as a voltage controller in power systems. It can help maintain the voltage magnitude at the bus it is connected to at a desired value during load variations. The SVC can both absorb as well as supply reactive power at the bus it is connected to by control of the firing angle of the thyristor elements. It is continuously controllable over the full reactive operating range as determined by the component ratings.

We can model the SVC as a variable reactive power source. Figure 4.4 shows the schematic diagram of a SVC and Figure 4.5 shows its control characteristics.

Figure 4.4 Schematic diagram of a SVC

The slope of the SVC voltage control characteristics can be represented as X_{SL}, the equivalent slope reactance in p.u. The limiting values of the SVC inductive and

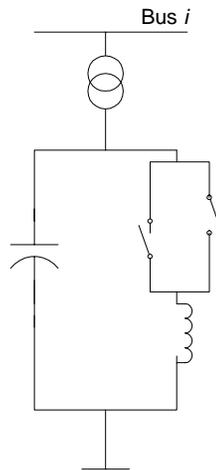capacitive reactances are given by X_L and X_C, respectively. V and V_{ref} are the node and reference voltage magnitudes, respectively. Modeling the SVC as a variable VAr source, we can set the maximum and minimum limits on the reactive power output Q_{SVC} according to its available inductive and capacitive susceptances B_{ind} and B_{cap}, respectively. These limits can be given as

$$Q_{\max} = B_{ind} \cdot V_{ref}^2 \tag{4.19}$$

$$Q_{\min} = B_{cap} \cdot V_{ref}^2 \tag{4.20}$$

where $B_{ind} = 1/X_L$ and $B_{cap} = 1/X_C$.
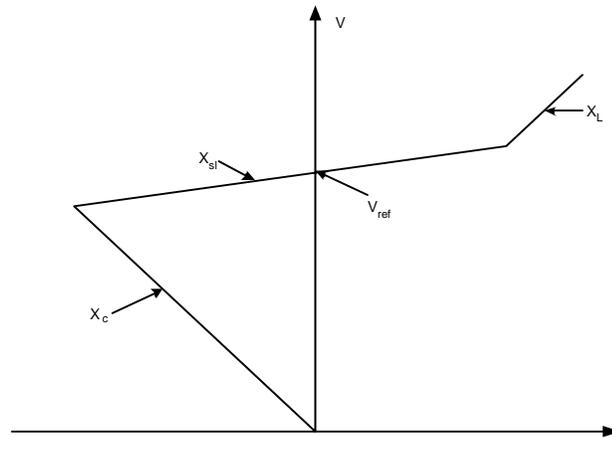
Figure 4.5 Control characteristics of a SVC

4.3 Problem Formulation for OPF with FACTS Devices

As seen in Chapter 3, the transmission dispatch in a deregulated environment may be a mix of pool and bilateral transactions. The optimal dispatch is comprised of complete delivery of all the transactions and the fulfillment of pool demand at least cost subject to nonviolation of any security constraint. It may be assumed that the ISO provides for all loss compensation services and dispatches the pool power to compensate for the transmission losses, including those associated with the delivery of contracted transactions. The normal dispatch problem is rewritten here as

$$\min_{P_{Gi}, P_{Dj}} \sum_i C_i(P_{Gi}) - \sum B_j(P_{Dj}) \tag{4.21}$$

subject to

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$$g(P_G, P_D, T_k, Q, V, \delta, F) = 0 \tag{4.22}$$

$$h(P_G, P_D, T_K, Q, V, \delta, F) \leq 0 \tag{4.23}$$

where P_{G_i} and P_{D_j} are the active powers of pool generator i with bid price C_i and pool load j with offer price B_j, respectively, and $P_G, P_D, T_k, Q, V, \delta$, and F are the vectors of pool power injections, pool power extractions, bilateral contracts, reactive powers, voltage magnitudes, voltage angles, and control parameter of FACTS devices placed in the line concerned. Equation (4.22) is a set of equality constraints comprising of the set of contracted transaction relationships and power balance equations. Equation (4.23) is a set of inequality constraints comprising of the system operating constraints.

If only bilateral transactions are considered, we may rewrite the dispatch formulation as

$$\min f(x, u)$$

where

$$f(x, u) = \sum_{i=2}^{m} \sum_{j=m+1}^{n} w_{ij} \cdot (T_{ij} - T_{ij}^0)^2 \tag{4.24}$$

subject to the real and reactive power balance equations

$$P_{G_i} + P_{i(inj)}^F + (P_{C_i} - P_{D_i}) - P_i = 0 \tag{4.25}$$

$$Q_{G_i} + Q_{i(inj)}^F + (Q_{C_i} - Q_{D_i}) - Q_i = 0 \tag{4.26}$$

and the inequality constraints,

where

$\quad n$ = number of buses in the power system, with the first m buses being gencos and the rest, discos

$\quad w_{ij}$ = the willingness to pay factor to avoid curtailment of transaction

$\quad T_{ij}^0$ = the desired value of transaction T_{ij}

$\quad P_{G_i}, Q_{G_i}$ are the real and reactive power generation at genco i

$\quad P_{D_i}, Q_{D_i}$ are the real and reactive load demand at disco i

$\quad P_{C_i}, Q_{C_i}$ are the real and reactive load curtailment at disco i

P_i , Q_i are the real and reactive power injection at bus i

$P^F_{i(inj)_i}$, $Q^F_{i(inj)}$ are the real and reactive power injection at bus i, with the installation of FACTS device

The modified OPF is different from the conventional OPF due to the FACTS related control variables. If it is desired to use the conventional linear programming based technique to solve the modified OPF problem, the solution strategy needs to be changed. This is because, with the introduction of the FACTS related control variables, the OPF no longer remains a linear optimization problem. One such strategy would be to separate the modified OPF problem into two subproblems, viz., the power flow control subproblem and the normal OPF problem. The power flow of the system can be obtained from the initial operation values of the power system. Using the power flow and constraint equations, the power flow control subproblem may be solved, thereby yielding the controllable FACTS devices' parameters. These parameters may then be used to solve the main OPF to obtain the conventional control variable values. Then if the solution of the power flow problem with the new control variables does not satisfy the constraint equations, this entire process is iteratively repeated until the mismatch falls below some predefined tolerance.

4.4   FACTS Devices Locations

We look at static considerations here for the placement of FACTS devices in the power system. The objectives for device placement may be one of the following:

1. reduction in the real power loss of a particular line
2. reduction in the total system real power loss
3. reduction in the total system reactive power loss
4. maximum relief of congestion in the system

For the first three objectives, methods based on the sensitivity approach may be used. If the objective of FACTS device placement is to provide maximum relief of congestion, the devices may be placed in the most congested lines or, alternatively, in locations determined by trial-and-error.

4.4.1 Reduction of total system VAr power loss

Here we look at a method based on the sensitivity of the total system reactive power loss (Q_L) with respect to the control variables of the FACTS devices. For each of the three devices considered in Section 4.2 we consider the following control parameters: net line series reactance (X_{ij}) for a TCSC placed between buses i and j, phase shift (α_{ij}) for a TCPAR placed between buses i and j, and the VAr injection (Q_i) for an SVC placed at bus i. The reactive power loss sensitivity factors with respect to these control variables may be given as follows:

1. Loss sensitivity with respect to control parameter X_{ij} of TCSC placed between buses i and j,

$$a_{ij} = \frac{\partial Q_L}{\partial X_{ij}}$$

2. Loss sensitivity with respect to control parameter θ_{ij} of TCPAR placed between buses i and j,

$$b_{ij} = \frac{\partial Q_L}{\partial \theta_{ij}}$$

3. Loss sensitivity with respect to control parameter Q_i of SVC placed at bus i,

$$c_i = \frac{\partial Q_L}{\partial Q_i}$$

These factors can be computed for a base case power flow solution. Consider a line connected between buses i and j and having a net series impedance of X_{ij}, that includes the reactance of a TCSC, if present, in that line. θ_{ij} is the net phase shift in the line and includes the effect of the TCPAR. The loss sensitivities with respect to X_{ij} and θ_{ij} can be computed as

$$\frac{\partial Q_L}{\partial X_{ij}} = [V_i^2 + V_j^2 - 2V_iV_j\cos(\delta_i - \delta_j)] \cdot \frac{R_{ij}^2 - X_{ij}^2}{(R_{ij}^2 + X_{ij}^2)^2} \tag{4.27}$$

and

$$\frac{\partial Q_L}{\partial \theta_{ij}} = -2aV_iV_jB_{ij}\sin\theta_{ij} \tag{4.28}$$

4.4.2 Selection of optimal placement of FACTS devices

Using the loss sensitivities as computed in the previous section, the criteria for deciding device location might be stated as follows:

1. TCSC must be placed in the line having the most positive loss sensitivity index a_{ij}.

2. TCPAR must be placed in the line having the highest absolute value of loss sensitivity index b_{ij}.

4.5 Test Cases

In this section we again consider the transmission dispatch problems treated in Sections 3.3.3 and 3.4.2. Here, the presence of FACTS devices in the power system is accounted for in the optimal power dispatch model.

4.5.1 Six-bus system

We consider the same system that was treated in Section 3.3.3. In this case, we solve the OPF with TCSC devices installed on two of the most congested lines in the system. To determine the optimal placement of the TCSC devices, we first perform the reactive power loss sensitivity analysis as developed in Section 4.4.1. The sensitivity index a_{ij} is computed for each line in the system and the result shown in Table 4.1

Table 4.1 VAr loss sensitivity index

Line	From bus	To bus	Sensitivity index
1	1	4	$a_{14} = -0.179$
2	1	6	$a_{16} = -0123$
3	2	3	$a_{23} = -0.23$
4	2	5	$a_{25} = -0.15$
5	3	4	$a_{34} = -0.0189$
6	4	6	$a_{46} = -0.0184$
7	5	6	$a_{56} = -0.044$

The lines having the most positive loss sensitivity index must be chosen for placement of the TCSC devices. For this we select lines 5 and 6 from Table 4.1.

When TCSC devices in the inductive mode of operation are connected in series with these two lines, with inductive reactances of 53.6% and 48.2% of the line reactances, respectively, it is seen that the line overloads are removed. The effect of optimal power dispatch with the TCSC devices installed on the line flows is shown in Table 4.2.

Table 4.2 Line flows

Line	From bus	To bus	Line flow (in p.u.)		
			Rated	Without FACTS devices	With TCSCs in lines 5 and 6
1	1	4	0.50	0.138	0.176
2	1	6	0.50	0.383	0.386
3	2	3	0.50	0.480	0.494
4	2	5	0.80	0.132	0.162
5	3	4	0.57	0.62	0.483
6	4	6	0.55	0.562	0.418
7	5	6	0.30	0.025	0.027

The constrained generation and load data may be obtained after running the OPF with the TCSCs installed. Table 4.3 shows a comparison between the data obtained with and without FACTS devices in the system for one particular curtailment strategy employed by the ISO (Case (1)).

Table 4.3 OPF results with and without TCSC

Bus #	Constrained generation and load, MW, Case (1) of 3.3.3	
	Without FACTS	With FACTS
1	109.63	109.72
2	124.24	124.41
3	34.72	34.96
4	48.87	49.14
5	40.74	41.32
6	53.99	53.99

This integrated framework covers the scenario where, even after putting the FACTS devices into operation, there is a need for the ISO to curtail the initial power transactions in order to maintain the system operation within security limits.

The OPF result shows that the individual power transactions suffer less curtailment when FACTS devices are included in the system.

4.5.2 Fourteen-bus system

We consider the same system that was treated in Section 3.4.2. Here, we solve the OPF for three different cases. In each case, one of the three FACTS controllers, viz., TCSC, TCPAR, and SVC, is included in the problem formulation. The static models of these devices, as developed in Section 4.2, are considered, i.e., a TCSC is represented as a static impedance, a TCPAR as a transformer with a complex tap ratio, and an SVC as a reactive power source with limits. The optimal locations for placing each of these devices can be determined by sensitivity analysis. In this problem we consider these three cases:

1. A TCSC placed between buses 3 and 11, operated with an inductive reactance of 59.3% of the line reactance

2. A TCPAR placed between buses 3 and 11, operated with a phase shift of –0.039 radians and unity tap ratio.

3. An SVC connected at bus 10, operating as a reactive power source of 0.13 p.u. within

limits of ±3.5 p.u., at a voltage of 1.05 p.u.

Here we consider only the Case (4) that was treated in Section 3.4.2. Table 4.4 shows the results of the OPF with Cases (A), (B) and (C) referring to the results obtained with TCSC, TCPAR, and SVC, respectively.

Table 4.4 OPF results with TCSC, TCPAR, and SVC

Bus #	Pre-curtailment MW	Constrained generation and load, MW		
		Case (A)	Case (B)	Case (C)
(group #1)				
2 (genco)	138.4	136.08	135.73	136.54
3 (genco)	92.6	90.29	91.36	90.60
7	54.3	53.76	53.81	53.46
9	91.5	89.93	90.67	90.31
11	56.6	55.31	55.20	55.25
14	28.6	27.37	27.40	28.12
(group #2)				
4 (genco)	213.5	208.31	210.81	210.52
8	155.4	155.26	155.30	155.25
10	16.8	13.36	14.97	15.36
12	13.1	11.87	12.71	12.07
13	28.2	27.81	27.83	27.82
(loss compensator)				
1 (genco)	38.1	36.85	37.32	36.22

4.6 Conclusions

This chapter has focused on dealing with congestion management using FACTS devices in an OPF framework. Comparative case studies with and without FACTS devices show the efficacy of FACTS devices in alleviating congestion. Optimal placement of these devices leads to improved congestion reduction and less curtailment in the desired power transactions.

5 CONCLUSIONS AND FUTURE WORK

The operational aspects of power systems pose some of the most challenging problems encountered in the restructuring of the electric power industry. In this report we looked at one such problem. This work focuses on congestion management within an OPF framework in a deregulated electricity market scenario. The conventional OPF problem is modified to create a mechanism that enables the market players to compete and trade and simultaneously ensures that the system operation stays within security constraints. The pool and bilateral dispatch functions of an ISO are dealt with. This report then focused on the use of FACTS devices to alleviate congestion. An integrated approach that includes FACTS devices in a bilateral dispatch framework to maintain system security and to minimize deviations from contractual requirements is then proposed. The approach is validated through numerical examples.

OPF is increasingly being used for transmission pricing and transaction evaluation in open access transmission systems. From the case studies carried out in this report, it was apparent that the interactions between market players are complex. Future work in this field may focus on quantifying the economic risk faced by market players due to differences in their willingness to pay to avoid curtailment. Research may also be carried out on designing different dispatch and curtailment strategies.

The sensitivity approach for determining optimal locations of FACTS devices can at best give an approximate idea about the optimal location for those devices in a deregulated environment. More reliable methods need to be developed for this.

Further, there is a need to apply object-oriented programming (OOP) techniques to the problem of OPF in a deregulated environment. That would facilitate the development of simpler and cheaper OPF packages.

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